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OFFSHORE OPERATORS COMMITTEE

October 17, 2000

Department of the Interior
Minerals Management Service
361 Elden Street, Mail Stop 4024
Herndon, Virginia 20170-4817

RULES PROCESSING TEAM
OCT 18 2000

RE: MINERALS MANAGEMENT SERVICE
PROPOSED RULE, SUBPART D
OIL AND GAS DRILLING OPERATIONS

Attention: Rules Processing Team (Comments)

Dear Sir:

The Offshore Operators Committee (OOC) appreciates this opportunity to provide written comments on the subject proposed rule to amend regulations regarding oil and gas drilling operations, as provided in the June 21, 2000 Federal Register Notice. The comments provided herein were prepared jointly with the American Petroleum Institute (API), and in cooperation with the International Association of Drilling Contractors (IADC).

The OOC supports the Mineral Management Service's (MMS) initiatives to update the applicable standards, practices and policies to eliminate confusion and facilitate better compliance, and willingness to consider recommendations from the OOC in this process. This cooperation between industry and government will help ensure that sound policies are developed.

The OOC is an organization of some 70 operating companies who conduct essentially all of the offshore oil and gas exploration and production activities in the GOM. Additionally, we have some 29 companies as associate members who are non-producers and supply services such as transportation, contract engineering or consulting, drilling, well and other services. The OOC has been interacting with groups concerned with OCS development in the GOM, including the various agencies responsible for managing or regulating OCS leases, for over 40 years now.
The following comments made on behalf of the OOC are provided without prejudice to an individual member's right to have or express different views.

Enclosed with this letter, is a document titled "RECOMMENDED REVISIONS TO PROPOSED 30 CFR 250 SUBPART D" which was developed by several member companies and other parties participating in the review of this proposed rule. The attached document contains recommended wording changes to the proposed in the text, along with our rationale for the proposed changes. Additionally, we have included requests for clarification in some areas. Also enclosed with this letter is a listing of general comments associated with the proposed rule which OOC believes are noteworthy.

Again, thank you for the opportunity to provide comments on the proposed rule and we appreciate your consideration of these comments. Please feel free to contact the undersigned at (504) 561-2427 (Allen_Verret@murphyoilcorp.com) or Mr. Steve Brooks at (504) 561-4753 (sbrooks@upstream.xomcorp.com) if you have any questions or wish to discuss in more detail.

Respectfully submitted,

Allen Verret, PE

Allen Verret, PE
Executive Director
Offshore Operators Committee

CC: Mr. Tim Sampson - American Petroleum Institute
Mr. Alan Spackman – International Association of Drilling Contractors

Attachments

GENERAL COMMENTS

In response to the Minerals Management Services request for comments, the following is a summary of concerns and comments expressed by the various OOC members regarding the proposed rule. These comments are general in nature and primarily address the information discussed in the Supplementary Information Section of the Federal Register notice:

New Form to Supplement the APD Information

OOC recognizes the need for the technical information to be provided on Form MMS-123S, replacing the unofficial practice of supplying an APD Information Spreadsheet. However, the standard form may require modifications to address the new information requirements addressed in the proposed rule. Consequently, OOC would welcome the opportunity to review this document, should changes need to be made to the form to capture the new information requirements.

Furthermore as discussed in the supplementary information, this form paves the way for electronic submittal of the drilling permit. OOC strongly supports this initiative and is working cooperatively through a special workgroup with the GOM Region to develop a system for electronic submittal of permits, plans and other data. We applaud MMS efforts in this regard, and look forward to continuing this dialog.

Waiting on Cement

OOC agrees with and commends the MMS regarding the inclusion of performance based language in the proposed rule concerning waiting time for cement. As stated, the complexity of cementing operations and variety of cements are not good candidates for prescriptive requirements. It is appropriate to hold the operator responsible for assessing when it is safe to nipple down well control equipment. As a prudent operator, this assessment is made based on a knowledge of formations conditions encountered, presence of potential drilling hazards, actual well conditions while drilling, cementing and post cementing as well as past experience.

Best Cementing Practices

OOC appreciates the MMS's welcoming of comments on the use of improved cementing practices to address some of the problems associated with sustained casing pressure. However, the intent of this supplementary discussion and request for comments is unclear. Moreover, operators have expressed concerns with the statement "while this approach has been successful for drilling and completing wells, we are less convinced that this approach has been successful for the long-term life of many wells." In the previous section titled Waiting on Cement, it is stated that "the complexity of cementing operations and variety of cements are not good candidates for prescriptive requirements." We likewise concur with this assessment as it applies to "Best Cementing Practices." That is, we have serious reservation with the MMS prescribing any type of "Best Cementing Practices".

GENERAL COMMENTS

Industry is participating in API/ISO Cementing Committee to address best cementing practices with the MMS and develop appropriate guidance for best cementing practices. Notwithstanding, most operating and service companies have established some form of "Best Practices" as guidelines for drilling and completion operations. While most share many common threads and concepts, each have subtle differences based on each company's research and experience. Since these internal Best Practices are "only" guidelines, they are subjective and are based on individual company research and experience. They are intended to focus on appropriate design and execution practices, which will lead to successful cement jobs. As such, they do not lend themselves to a prescriptive rule.

Accordingly, OOC members will support the MMS's efforts to review and define guidance regarding best cementing practices, but will oppose the inclusion of prescriptive cementing practice requirements, over the current performance based requirements.

Blind-shear Ram for Surface BOP Systems

The OOC strongly opposes the new requirement to install blind-shear rams on all surface-BOP stacks within one year of the effective date of this proposed rule. Industry has reviewed the description of the incidents used by the MMS to justify the proposed requirement to install blind-shear rams in all BOP stacks, and disagrees with the conclusion that they support the need to require the installation of blind-shear rams. Moreover, we have reviewed the comments, regarding the proposed revision to Subpart D, as provided to the MMS from the International Association of Drilling Contractors (IADC) and fully concur with the comments and recommendations presented therein.

The MMS speculates that there will be the need to retrofit approximately 80 BOP stacks with blind-shear rams. A survey conducted by IADC has identified over 160 stacks that will require modification. This survey contains the total number of surface stacks in the contractors' inventories that are marketed for the U.S. OCS operations, including active and inactive rigs, rental stacks and stacks on well servicing rigs. Even accepting the need to install blind-shear rams, the time frame of one-year to retrofit 160 BOP stacks is clearly inadequate, due to equipment availability. Furthermore, using MMS estimates, a 13-5/8 inch blind-shear ram would cost the drilling contractor an estimated $175,000 to manufacture, transportation and install. The total cost impact to the drilling contractors in the one-year period following the effective date of this requirement could be in excess of $25 million; and although the OOC does not agree with many of the assumptions made by the MMS in estimating cost to the lessee/operator under the Regulatory Flexibility Act, these costs should be adjusted to account for the 160 BOP stacks which require retrofitting. Also, it does not appear that the MMS has included the cost impact associated with completion operations and workover rigs. More importantly, while this proposed rule may not have an effect of $100 million or more on the economy, the cost impact of this requirement is significant when considering that it does not appear to appreciably reduce the risk of blow-outs, as discussed in the IADC comments.

Other Considerations for Drilling Regulations

GENERAL COMMENTS

In response to MMS's request for comments on regulations for coiled tubing drilling, we concur with the MMS approach to rulemaking in that regard. We agree that a better understanding of these operations and the amount of activity that is likely to take place on the OCS is necessary before drafting regulations. In the interim, we believe that the existing/proposed provisions in Subpart D, coupled with the District Supervisors' authority to approve alternative techniques and procedures, adequately addresses the regulatory mandates. OOC likewise supports the use of API RP 5C7 as guideline when preparing the appropriate regulations.

In accordance with the MMS's request for comments on requiring automated pipe handling systems, we recognize the potential to reduce personnel exposure offer by automated systems and would agree that operators should continue to influence our contractors to upgrade and improve as industry experience and familiarity with these systems increase. However, too little data exists to support the theory that such systems measurably improve personnel safety. Furthermore, we are again disturbed by the prescriptive nature of such a requirement as discussed therein. In regards to these type operations, we believe a performance-based initiative is much more suitable. Again, we have reviewed and concur with the IADC regarding automated pipe handling systems. In addition, it should be understood that the prime driver for such systems on drillships and semis was to compensate for motion-related safety conditions and operability while tripping, not one of safety simply for tripping.

Proposed Section Number	Proposed Text	OOC Recommended Changes/Comments	Rationale
Documents Included by Reference			
250.198	**Documents Included by Reference.** API RP 500, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities, First Edition, June 1, 1991, API Stock No. G06005.	API RP 500, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified **as Class 1, Division 1 and Division 2, Second** Edition, November 1997, API Stock **No. C50002.** **API RP 505, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class 1, Zone 0, Zone 1, Zone 2, First Edition, November 1997, API Stock No. C50501.**	By Federal Register Notice dated January 4, 2000, MMS incorporated by reference API RP 500, Second Edition and API RP 505, First Edition. Proposed Rule should be modified to state such.
General Requirements			
250.401	**What must I do to keep wells under control?** You must take necessary precautions to keep wells under control at all times. You must: ... (b) Have a person onsite that represents your interests and can fulfill your responsibilities; (c) Ensure that the toolpusher or a member of the drilling crew maintains continuous surveillance of the rig floor from the beginning of drilling operations until the well is abandoned, unless you have secured the well with blowout preventers (BOPs) or packers;	(b) Have a person onsite **24 hours per day during operations** that represents your interests and can fulfill your responsibilities; (c) Ensure that the toolpusher or a member of the drilling crew maintains continuous surveillance of the rig floor from the beginning of drilling operations until the well is abandoned **or completed**, unless you have secured the well with blowout preventers (BOPs), **bridge plugs, cement plugs** or packers;	Include 24 hours a day to provide clarity. Well may go from drilling to completion and not be abandoned. Additionally, bridge plugs and cement plugs are viable options for securing the well.
250.402	**When and how must I secure a well?** Whenever you interrupt **drilling** operations, you must install a downhole safety device, such as a cement plug, bridge plug, or packer. You must install the device as deep as possible within a	**When and how must I secure a well?** Whenever you interrupt **drilling** operations, you must install a downhole safety device, such as a cement plug, bridge plug, or packer. You must install the device ~~as deep as possible~~ **at an appropriate depth** within a properly cemented	The use of the phrase "as deep as possible" infers that the device should be set at the bottom of the hole. By changing "as deep as possible" to "an appropriate depth" allows the operator the flexibility to choose appropriate setting depths. For example, Mechanical packers are frequently used

	properly cemented casing string. (a) Among the events that may cause you to interrupt drilling operations…	casing string **or liner.** (a) ~~Among~~ The events that may cause you to ~~interrupt~~ **temporarily suspend drilling operations or:**	to secure a well. The packers typically have hydraulically actuated hold down slips to prevent the packer from moving up hole when exposed to pressure from below the packer. These hold down slips require approximately 800 to 1000-psi pressure differential before they will engage the casing thus becoming effective. Sufficient drill string weight must be hung off below the packer to prevent the packer from moving up hole when exposed to pressure from below prior to the hold down slips becoming effective. This drill string weight is typically hung off in casing and not open hole to prevent incidence of stuck pipe. Hence it is reasonable to set the device as deep as practical, allowing for adequate hang off weight (inside cased hole) below the packer. Furthermore, in the event of an emergency evacuation, the isolating device may be set shallow when time is of the essences. The proposed text regarding what types of events require securing of well downhole is vague and open-ended. Therefore we recommend the word "among" in paragraph (a) be deleted, and the remainder of the paragraph be amended as recommended to detail the specific type events,
250.403	**What safety requirements must my drilling unit meet?** Your drilling unit must meet all of the safety requirements in this section.		which is consistent with existing requirements.
Required Safety Measure **…**	**When Required** — **Additional Requirements**		
(c) Shut in all producible wells located in the affected wellbay…	When you move a drilling rig or related equipment on a platform. — You must shut in each well below the surface and at the wellhead, unless otherwise approved by the District Supervisor.	Clarity requested.	The language proposed is very vague. It appears that a subsurface shut-in is only required to move a rig while located on a platform (i.e. from well to well) and does not address rigging-up and rigging-down. Also applicability to MODU's is unclear (movement of cantilever jack-ups and floaters).

Applying for a Permit to Drill			
250.410	**How can I apply for a permit to drill a well?** (a) You must obtain ... (b) You must submit the following forms to the District Supervisor: ... (3) Form MMS-123S, APD Information Sheet	Form MMS 123S may require modifications to include addition information requirements. OOC requests that we be allowed to review and provide comments to the MMS, if the form is modified.	We assume that Form MMS 123S will be modified to contain new information requirements. Therefore, we believe it would be beneficial to both industry and the MMS to allow OOC to review the new form.
250.413	**What items must my description of well drilling design criteria address?** (a) Pore Pressure... (h) A summary report of the shallow hazards site survey that describes the geological and manmade conditions; and	(h) Delete	We recommend that Line (h) be deleted. It is not clear how is this additional summary to be submitted. (i.e. Is it to be included in Form MMS 123s, or is it a narrative summary to part of the ADP, or is it a separate submittal?) The language as proposed is unclear, and OOC is not sure of the intent, or the purpose of this additional reporting requirement. Additionally, the summary report of the shallow hazards site survey will have been previously submitted with the EP/DOCD under which the well will be drilled.
250.414	**What items must my drilling prognosis include?** (a) Projected plans for coring at specified depths; (b) Projected plans for logging; (c) Planned safe drilling margin between proposed drilling fluid weights and estimated pore pressures. This safe drilling margin may be shown on the plot required by Sec. 250.413(g); (d) Estimated depths to the top of significant marker formations; (e) Estimated depths to significant porous and permeable zones containing fresh water, oil, gas, or abnormally pressured formation fluids; (f) Estimated depths to faults; and (g) Estimated depths of permafrost, if applicable.	Clarity is requested for lines (a) (b)(d)(e)(f) and (g). (f) Estimated depths to **major** faults; and	Currently the majority of this data is capture in the APD Information Spreadsheet. However, will the proposed Form MMS-123S include other required data, such as estimated depths to the top of significant marker formations, major faults etc. OOC assumes that the intent of this requirement is to identify faults that can potential lead to problems while drilling, therefore we recommend that the language be modified to include major faults only.
250.415	**What items must my casing and cementing programs include?** (a) Hole sizes and casing sizes, including: weights; grades; tension,	(a) Hole sizes and casing sizes, including: weights; grades; ~~tension,~~ collapse, and burst	The requirement for including the tension value has been deleted from the proposed language.

	collapse, and burst values; types of connection; and setting depths (measured and true vertical depth); ...	values; types of connection; and setting depths (measured and true vertical depth)...	This information has not been required in the past. The need to now require this information is unclear. If this requirement remains, will the ADP Information Spreadsheet/Form MMS-123S, be revised to capture these values?
250.417	**What information must I provide if I intend to use a mobile drilling unit to drill a proposed well?** (a) Fitness requirements. You must provide information and data to demonstrate the drilling unit's capability to perform at the proposed drilling operation. This information must include the maximum environmental and operational conditions that the unit is designed to withstand, including the minimum air gap necessary for both hurricane and non-hurricane seasons. If sufficient environmental information and data are not available, the District Supervisor may require you to collect and report this information. (b) Foundation requirements. You must provide information to show that site-specific soil and oceanographic conditions are capable of supporting the proposed drilling unit. If you provided sufficient site-specific information in your EP, DPP, or DOCD, you may reference that information. The District Supervisor may require you to conduct additional surveys and soil borings before approving the APD.	(a) ... If sufficient environmental information and data are not available, the District Supervisor may require you to collect and report this information **during the period of operation. The information to be collected and reported will be related to the structural integrity of the drilling unit and the safe conduct of operations.** (b) ... The District Supervisor may require you to conduct additional surveys and soil borings before approving the APD, **if the District Supervisor cannot make a determination that the proposed drilling unit can be supported at the specific site.**	Clarity. The proposed language is too broad and does not present under which conditions the additional data would be required.
250.420	**What well casing and cementing requirements must I meet?...** (b) Casing Requirements. (1) You must design casing (including liners) to withstand the anticipated stresses imposed by tensile, compressive, and buckling loads; burst and collapse pressures; thermal effects; and combinations thereof.	(b) Casing Requirements. (1) You must design casing (including liners) to withstand the anticipated stresses imposed by tensile, compressive, and buckling loads; burst and collapse pressures; thermal effects~~; and combinations thereof~~.	OOC recommends that the phrase "and combinations thereof" be deleted because this statement is vague as to what combinations must be considered.

	(2) The casing design must include safety measures that ensure well control during drilling and safe operations during the life of the well.		(2) The casing design must include safety measures that ensure well control during drilling ~~and safe operations during the life of the well~~.	OOC recommends that the phrase "and safe operations during the life of the well" be deleted because it is too broad.
250.421	**What are the casing and cementing requirements by type of casing string? …**			
Casing Type	**Casing Requirements**	**Cementing Requirements**		
(b) Conductor	Design casing and select depths based on relevant engineering and geological factors. These factors include …	Use enough cement to fill the annular space back to the mudline. Verify annular fill by observing cement returns. If you cannot observe cement returns, use additional cement to ensure fill-back to the mudline. For drilling on…	(b) Use enough cement to fill the annular space back to the mud line. Verify annular fill by observing cement returns. If you cannot observe cement returns, use additional cement to ensure fill back to the mud line. **Excess cement may be washed out from the annulus below the mud line to a sufficient depth as necessary to facilitate well abandonment operations.** For drilling …	Cement in the annular area between the conductor and the drive/structural pipe can cause difficulty in cutting pipe and clearing the location below the mud line.
(f) Liners	If you use a liner as conductor or surface casing, you must set the top of the liner at least 200 feet above the previous casing/liner shoe. If you use a liner as an intermediate or production casing, you must set the top of the liner at least 100 feet above the previous casing	Same as the cementing requirements for the specific casing types. For example, a liner used as an intermediate casing must be cemented according to the cementing requirements for intermediate casing.	If you use a liner as conductor or surface casing, you must set the top of the liner at least 200 feet above the previous casing/liner shoe. If you use a liner as an intermediate or production casing, you must set the top of the liner at least 100 feet above the previous casing shoe, **unless otherwise approved by the District Supervisor.**	It is common practice to achieve the liner-lap lengths discussed herein. However there are instances when this is undesirable, and in those cases a liner top packer is typically installed to ensure a good seal. The recommended language change will provide the District Supervisor the flexibility to approve a shorter liner-lap. Additionally, existing regulations include language that prohibits the use of a production liner when landed in a surface casing. Is this no longer the case?

	shoe.			
250.422	**When may I resume drilling after cementing? ...** (b) If you plan to nipple down your diverter or BOP stack during the 8- or 12-hour waiting time, you must determine, in advance, when it will be safe to conduct this activity. Your determination must consider cement composition, well conditions, and the effects of nippling down the equipment.	(b) If you plan to nipple down your diverter or BOP stack during the 8- or 12-hour waiting time, you must determine, ~~in advance~~ when it will be safe to conduct this activity. Your determination must be **based on a knowledge of formations conditions encountered, presence of potential drilling hazards, actual well conditions while drilling, cementing and post cementing as well as past experience.**		The term "in advance" in the proposed text is very vague. We recommend it be removed and the actual information necessary to make the determination be stated. However, we do agree that the performance based language as written in 250.422(b) is appropriate. That is, making the operator responsible for assessing when it is safe to nipple down well control equipment. As a prudent operator, this assessment is made based on a knowledge of formations conditions encountered, presence of potential drilling hazards, actual well conditions while drilling, cementing and post cementing as well as past experience.
250.423	**How must I remedy cementing and casing problems and situations?** The table in this section describes remedies to problems and situations that lessees encounter on a regular basis during casing and cementing activities.			
If you have the following problem or situation:	**Then you must ...**	**If you have the following problem or situation:**	**Then you must ...**	
(b) Change casing setting depths more than 100 feet from the approved APD...	Submit those changes to the District Supervisor for approval.	(b) Change casing setting depths more than 100 feet **TVD** from the approved APD.	Submit for approval changes to the District Supervisor if casing setting depth is deeper than 100 feet TVD and notify the District Supervisor is the casing is set shallow than 100 TVD from the approved setting depth.	It is recommended that approval be obtained if the casing depth change is more than 100 feet true vertical depth, not measured depth. Additionally, if the casing becomes stuck while running or other hole conditions prevent the running of casing to the projected setting depth, the operator should be allowed to cement the casing without seeking approval, and notify the District Supervisor subsequently.
(h) Plan to drill a well without setting	Submit geologic data and information to the District Supervisor that demonstrates the absence of shallow hydrocarbons or hazards. This information must include logging and	Submit geologic data and information to the District Supervisor that demonstrates the absence of shallow hydrocarbons or hazards. This information must include logging, ~~and~~ drilling fluid-monitoring **and other available geologic data**		The 500-foot limit is too prescriptive. This waiver should be based on the geologic data from an applicable analogous well.

conductor casing.	drilling fluid-monitoring from wells previously drilled within 500 feet of the proposed well path down to the next casing point.	from wells previously drilled ~~within 500 feet~~ **in the immediate vicinity** of the proposed well path down to the next casing point.	
250.424	**What are the requirements for pressure testing casing?** (a) You must pressure test each string of casing to 70 percent of its minimum internal yield. This testing requirement does not apply to drive or structural casing. When a diverter is installed on conductor casing, you must test the casing to a minimum of 200 psi. The District Supervisor may approve or require other casing test pressures.	(a) You must pressure test each string of casing to 70 percent of its minimum internal yield **or as otherwise approved by the District Supervisor**. This testing requirement does not apply to drive or structural casing. When a diverter is installed on conductor casing, you must test the casing to a minimum of 200 psi. ~~The District Supervisor may approve or require other casing test pressures.~~	The are more than one currently approved method for calculating casing test pressure. They are: Method 1: Test pressure limited by 70% of the casing burst rating less mud weight hydrostatic used to test and pore pressure effects. Method 2: Test pressure limited to the pressure integrity of the casing shoe less a gas gradient inside the casing plus 500-psi. Method 3: Test Pressure limited to a potential kick pressure less the effects of the total displaced mud volume, plus 500-psi. Method 4: Test pressure limited to the production interval bottom hole pressure less a gas gradient inside the casing plus 500-psi. Method 5: Applicable to protective liners. Test pressure equivalent to the previous test pressure of the upper casing string at the liner top TVD. We recommend that the alternative test methods be included in the new requirements, or allow the District Supervisor the discretion to approve alternative methods.
Diverter System Requirements			
250.431	**What are the diverter design and installation requirements?** You must design and install your diverter system to: (a) Use diverter spool outlets and diverter lines that have an internal diameter of at least 10 inches for surface wellhead configurations and at least 12 inches for floating drilling operations; ...	(a)Use diverter spool outlets and diverter lines that have ~~an internal diameter~~ **a nominal diameter** of at least 10 inches for surface wellhead configurations and at least 12 inches for floating drilling operations	API line pipe is normally used for diverter lines. Line pipe is different than casing. The nominal size of line pipe normally refers to the OD (for larger sizes).
250.434	**What are the recordkeeping requirements for diverter tests?** You must record the time, date, and results of all diverter actuations and tests in the driller's report. In addition, you must: ...	(f) After drilling is completed, ~~retain all the records listed in this section for 2 years at the facility, at the lessee's field office nearest to the facility, or at another location conveniently available to the District Supervisor.~~ **the lessee must retain all the records listed in this section for 2 years**	To require the lessee to maintain detailed drilling records at the facility or at the nearest field location after drilling is completed is unreasonable, and places an unnecessary record keeping burden on the operator. We do maintain these records; however, they are typically maintained in a central

	(f) After drilling is completed, retain all the records listed in this section for 2 years at the facility, at the lessee's field office nearest to the facility, or at another location conveniently available to the District Supervisor.	**and make them available at the District Supervisor's request.**	record center. The need to maintain test results in the field after the drill operations are completed is unclear. Should the need to review these records arise, they can be supplied at that time.
Blowout Preventer (BOP) System Requirements			
250.440	**What are the general requirements for BOP systems and system components?** You must design, install, maintain, and use the BOP system and system components to ensure well control. The working-pressure rating of each BOP component must exceed maximum anticipated surface pressures. The BOP system includes the BOP stack and associated BOP systems and equipment.	You must design, install, maintain, **test** and use the BOP system and system components to ensure well control...	Include test in the proposed text to be complete and consistent with the existing requirements.
250.441	**What are the requirements for a surface BOP stack?** (b) One year after the effective date of this final rule, the surface BOP stack must have at least four remote-controlled, hydraulically operated BOPs consisting of an annular preventer, two preventers equipped with pipe rams, and one preventer equipped with blind-shear rams.	(b) Delete	We strongly recommend that this requirement be eliminated. We have reviewed the description of the incidents used by the MMS to justify the proposed requirement to install blind-shear rams in all BOP stacks and disagree with the conclusion that they support the need to require the installation of blind-shear rams. Furthermore, a 13-5/8 inch blind-shear rams would cost the drilling contractor an estimated $82,000 plus transportation and installation costs. The total estimated cost imposed by this requirement would be $150,000 per stack. Moreover, we have reviewed the comments, regarding the proposed revision to Subpart D, as provided to the MMS from the International Association of Drilling Contractors (IADC) and fully concur with the comments and recommendations presented therein.
250.442	**What are the requirements for a subsea BOP stack? ...** (b) You must install a subsea accumulator closing unit to provide fast closure of the BOP components and to	(b) You must install a subsea accumulator closing unit, **or equivalent systems** to provide fast closure of the BOP components and to operate all	Many BOP stacks on floating drilling rigs currently in operation, do not meet the proposed requirement to install a subsea accumulator. In

	operate all critical functions in case of a loss of the power fluid connection to the surface. The subsea accumulator must meet or exceed the provisions of Section 13.3, Accumulator Volumetric Capacity, in API RP 53, Recommended Practice for Blowout Prevention Equipment Systems for Drilling Wells. The District Supervisor may approve a suitable alternate method. (d) Before removing the marine riser, you must displace the riser with seawater. You must maintain sufficient hydrostatic pressure or take other suitable precautions to compensate for the reduction in pressure and to maintain a safe and controlled well condition.	critical functions in case of a loss of the power fluid connection to the surface. The ~~subsea~~ accumulator must meet or exceed the provisions of Section 13.3, Accumulator Volumetric Capacity, in API RP 53, Recommended Practice for Blowout Prevention Equipment Systems for Drilling Wells. The District Supervisor may approve a suitable alternate method. (d) Before removing the marine drilling riser, you must displace the riser with seawater, **except in the case of an emergency riser disconnect**. You must …	lieu of subsea accumulators, the inclusion of redundant power/control lines provides the equivalent protection necessary. Therefore, we recommend the inclusion of the statement "or equivalent system" to the proposed language. Drillships and semi submersible drilling rigs with automatic station keeping (ASK) systems may experience ASK failures at which time the well must be isolated with the BOP and the marine riser disconnection immediately to prevent damage to well, equipment and rig. It is therefore impractical to displace the marine riser with seawater prior to an emergency riser disconnect.
250.447	**When must I conduct BOP system pressure tests?** You must pressure test your BOP system (this includes the choke manifold, kelly cocks, inside BOP, and drill-string safety valve): … (b) Before 14 days have elapsed since your last BOP pressure test. You must begin to test your BOP system before midnight on the 14th day following the conclusion of the previous test. However, the District Supervisor may require more frequent testing if conditions or BOP performance warrant; and …	(b) Before 14 days have elapsed since your last BOP pressure test. You must begin to test your BOP system before midnight on the 14th day following the conclusion of the previous test. However, the District Supervisor may ~~require more frequent testing~~ **require the test to be performed before midnight on the 7th day following the conclusion of the previous test,** if conditions or BOP performance warrant; and	More frequent testing without a specified interval is too broad.
250.448	**What are the BOP pressure tests requirements?** When you pressure test the BOP system, you must conduct a low-pressure and a high-pressure test for each BOP component. You must conduct the low-pressure test before		

	the high-pressure test. Each individual pressure test must hold pressure long enough to demonstrate that the tested component(s) holds the required pressure. Required test pressures are as follows: …		
	(b) High Pressure tests for ram type…	(b) Clarity requested.	OOC recognizes and appreciates the MMS efforts to allow for BOP high-pressure tests requirements to include either testing to rated working pressure, or to 500 psi above the maximum allowable Surface Pressure (MASP) for the applicable section of the hole. However, we recommend that the proposed rule include acceptable methods for calculating MASP, to provide clarity.
	(c) High pressure test for annular-type BOPs. The high pressure test must equal 70 percent of the rated working pressure of the equipment.	(c) High pressure test for annular-type BOPs. The high pressure test must equal 70 percent of the rated working pressure of the equipment, **or as otherwise approved by the District Supervisor**	Currently approved procedures for testing annular preventers allow for testing to a pressure less than 70% of the working pressure, such as testing to the MASP.
250.450	**What are the recordkeeping requirements for BOP tests?** You must record the time, date, and results of all pressure tests, actuations, and inspections of the BOP system, system components, and marine riser in the driller's report. In addition, you must: …		
	(c) Document the sequential order of BOP and auxiliary equipment testing and the pressure and duration of each test. For subsea BOP systems, you must also record the closing times for annular and ram preventers. You may reference a BOP test plan if it is available at the facility;	(c) Document the sequential order of BOP and auxiliary equipment testing and the pressure and duration of each test. ~~For subsea BOP systems, you must also record the closing times for annular and ram preventers.~~ You may reference a BOP test plan if it is available at the facility	The requirement to record closing times should be removed. This requirement is not a common practice. Furthermore, there is no requirement for maximum closing time of a BOP, and it is unclear how the measurement of closing time would be determined (is it from the time the button is pushed until the fluid flow stop, or the time it takes the ram to fully stroke?). We do not see the value added by recording this time. Either, a BOP stack functions properly or not.
	(g) After drilling is completed, you must retain all the records listed in this section for a period of 2 years at the facility, at the lessee's field office nearest the facility, or at another	(g) After drilling is completed, ~~retain all the records listed in this section for 2 years at the facility, at the lessee's field office nearest to the facility, or at another location conveniently available to the District Supervisor.~~ **the lessee must retain all**	To require the lessee to maintain detailed drilling records at the facility or at the nearest field location after drilling operations are completed is

	location conveniently available to the District Supervisor.	**the records listed in this section for 2 years and make them available at the District Supervisor's request.**	unreasonable, and places an unnecessary record keeping burden on the operator. We do maintain these records; however, they are typically maintained in a central record center. The need to maintain test results in the field after the drill operations are completed is unclear. Should the need to review these records arise, they can be supplied at that time.
Drilling Fluid Requirements			
250.457	**What equipment must I have to test and monitor drilling fluids?** (a) You must have and maintain drilling fluid-testing equipment on the drilling rig at all times. You must test the drilling fluid at least once each tour, or more frequently if conditions warrant. You must perform the tests according to industry-accepted practices. Tests must include density, viscosity, and gel strength; hydrogen-ion concentration; filtration; and any other tests the District Supervisor requires. You must record the results of these tests in the drilling fluid report...	(a) You must have and maintain drilling fluid-testing equipment on the drilling rig at all times. You must test the drilling fluid**, when circulating** at least once each tour or more frequently if conditions warrant. You must perform the tests according to industry-accepted practices. Tests must include density, viscosity, and gel strength; hydrogen-ion concentration; filtration; and any other tests the District Supervisor requires **for monitoring and maintaining drilling fluid quality for safe operations, prevention of downhole equipment problems and for the detection of kicks.** You must record...	There are many times on a rig when circulation does not occur during a tour, or longer, and testing twice per day (once each tour) has no added value. Therefore, we recommend that this be a requirement during circulation only. Furthermore, the proposed text is too broad in regards to what type and why might the District Supervisor require additional test. The recommended language is consistent with the existing requirements.
Other Drilling Requirements			
250.460	**What are the requirements for well testing?** (a) You must determine the presence, quantity, quality, and reservoir characteristics of oil, gas, sulphur, and water in the formations penetrated by logging, formation sampling, or well testing...	Clarity requested.	The proposed language is confusing. The title of this section is "What are the requirements for well testing?" However, paragraph (a) discusses determining formation characteristics using formation fluid samples and logging. It seems appropriate to put this paragraph in a section titled "what type samples, survey and tests of the formation are required." Please refer to 30 CFR 250.401(e) in the existing regulations.
250.461	**What are the requirements for directional and inclination surveys?** For this subpart, MMS classifies a well as vertical if the calculated average of inclination readings does not exceed 3 degrees from the vertical. (a) Survey requirements for a vertical well: (1) You must conduct inclination	(a) Survey requirements for a vertical well:	Digitally recording inclination surveys while drilling

	surveys on each vertical well and digitally record the results. Survey intervals may not exceed 1,000 feet during the normal course of drilling; (2) You must also conduct a directional survey that provides both inclination and azimuth: ... (e) If you drill within 500 feet of an adjacent lease, the Regional Supervisor may require you to furnish a copy of the well's directional survey to the affected leaseholder.	(1) You must conduct inclination surveys on each vertical well and ~~digitally~~ record the results. Survey intervals... (2) You must also conduct a directional survey that provides both inclination and **azimuth, and digitally record the results in electronic format:** ... (e) If you drill within 500 feet of an adjacent lease, the Regional Supervisor may require you to furnish a copy of the well's directional survey to the affected leaseholder, **if the leaseholder has ~~requested the survey.~~**	a vertical well is not necessary or practical. Inclination surveys are used as a process control check to ensure that the well remains near vertical. The subsequent surveys, which include both inclination and azimuth, can be digitally recorded in electronic format. The phrase "electronic format" has been add to clarify that the record should be stored electronically for submittal to MMS, not record as "fingers" on a paper copy. The adjacent leaseholder should request the ~~survey.~~
250.462	**What are the requirements for well-control drills?** You must conduct a weekly well-control drill with each drilling crew. Your drill must familiarize the crew with its roles and functions so that all crewmembers can perform their duties promptly and efficiently... (d) MMS ordered drill. An MMS authorized representative may require you to conduct a well control drill during an MMS inspection. The MMS representative will consult with you ~~before requiring the drill.~~	(d) MMS ordered drill. An MMS authorized representative... The MMS representative will consult with **your onsite representative** before requiring the drill.	Clarifies who will be consulted prior to conducting the drill.
Sundry Notices and Well Records			
250.465	**When must I submit sundry notices to MMS?** (a) You must submit sundry notices (form MMS-124) and other materials to the Regional Supervisor as shown in the following table. You must also submit a public information copy of each form.		

If you....	**then you must....**	**and...**		
(1) Intend to revise plans,	Submit form MMS-	Receive written or oral approval from the District Supervisor before you	Receive written or oral approval from the District Supervisor before you begin the intended operation. If you get an oral approval, you must	With weekends and holidays it is often difficult to meet the 72-hour limitation.

change major drilling equipment, deepen, plug-back, or sidetrack a well.	124 or request oral approval.	begin the intended operation. If you get an oral approval, you must submit form MMS-124 within 72 hours. In all cases, you must meet the additional requirements in paragraph (b) of this section.	submit form MMS-124 ~~within 72 hours~~. **no later than the end of the 3rd business day following the oral approval.** In all cases, you must meet the additional requirements in paragraph (b) of this section.	
250.466	**What well records must I keep?** You must keep complete, legible, and accurate records for each well. You must keep these records at your field office nearest the OCS facility or at another location conveniently available to the District Supervisor. The records must contain complete information on all of the following: … (g) All other information required by the District Supervisor.		(g) All other information required by the District Supervisor **in order to evaluate resource evaluation, waste prevention, conservation of natural resources, protection of correlative rights, safety or protection of the environment.**	Proposed language is very broad. The recommended language clarifies under what circumstances will additional information be requested.
250.467	**What well records may I be required to submit?** The Regional or District Supervisor may require you to submit copies of all the well records listed in this section…		Delete section.	As written, this section appears to be for informational purposes, rather than a requirement. Furthermore, the proposed language is vague. Line (a) discusses an NTL; Line (b) Specifies requirements for GOMR, but is silent on requirements for other regions, Line (c) as written appears that this is not mandatory, but at the discretion of the District Supervisor, and Line (d) eliminates the prescriptive requirements for legible, ~~exact copies of service company records~~.
Changes to Other Subparts				
250.515 (b)	The minimum BOP system for well-completion operations must meet the appropriate standards from the following table:			
When…	**the minimum BOP stack must include…**			

(5) It is one year from the final rule effective date	At least one set of blind-shear rams.	Delete this requirement	Please refer to rationale previously discussed in Section 250.441 of this document.
250.615 (b)	(b) The minimum BOP system for well-workover operations with the tree removed must meet the appropriate standards from the following table:		
(5) It is one year from the final rule effective date	At least one set of blind-shear rams.	Delete this requirement	Please refer to rationale previously discussed in Section 250.441 of this document.